CDM report of biomass power project in Tamilnadu

Prepared for **Sane Renewable Energy Pvt. Ltd (SREPL), Tamilnadu**

TERI Project Report No. 2002RT62

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1 Background

M/s Sane Renewable Energy Pvt. Ltd (SREPL) is in the process of implementing a 6 MW biomass based power plant in Village Vanur, District Villupuram, Tamilnadu.

SREPL approached TERI for carrying out the following activities:

- Review of project documents to establish
  - its techno-economical feasibility
  - sustainability of the biomass supply
- Developing project under Clean Development Mechanism (CDM) by analysing and formulating the following:
  - Study the base line
  - Evaluating additionalities
  - Estimate CER generation
  - Outlining M&V requirements

TERI visited the project site, office of the client and their consultant namely M/s Aqua Therm Engineering Consultants (India) P Ltd., Chennai, Tamilnadu. TERI had detailed discussions with the local biomass growers and dealers, project management and the project consultant on the contents of the DPR with respect to selection of technology, design, biomass handling, water requirement and O&M.

Based on the visit, discussion and review of the DPR, a brief review report on the biomass sustainability and on DPR for the proposed 6 MW project have been prepared.

Further as per the terms of reference, a CDM report on the proposed project has also been prepared which is discussed below in this report.

Clean Development Mechanism

The Kyoto Protocol within the UNFCCC set limits on the emissions of developed countries (Annex 1) in the 2008-2012 period, also known as the first commitment period. Towards this goal, the Kyoto Protocol formulated mechanisms known as 'flexibility mechanisms' in which they accord Annex 1 countries the flexibility in meeting their GHG abatement limits through the following routes:

- Emission trading
- Joint implementation (JI/AIJ)
- Clean development mechanism (CDM)

While the first two mechanisms are essentially between developed countries, CDM is implemented between developed and developing countries.

CDM is essentially a project-based GHG emissions offset trading program between countries with GHG emissions reduction commitments and those without. It is project-based and participants must have their projects certified by an independent reviewer. The emissions reductions achieved by certified projects are called certified emissions reductions (CERs) and are expected to be the basis for an international market in carbon emission. The CER becomes a tradable commodity through which the CDM aims to provide mutually shared benefits for investors and hosts. As a mechanism intended to channel private sector investment towards climate friendly projects, the CDM aims to support the development of a new set of international arrangements for public/private partnership. Besides GHG emissions offset objective, equally important is to achieve sustainable development in the developing nations through the CDM route.

In order for CDM to be effective in ensuring additional carbon-emissions reductions, the transfer of cutting-edge climate-friendly technologies—mainly energy-efficient and renewable energy technologies—is seen as essential. The rapid penetration of these technologies in the developing world would provide these economies with such climate-friendly technologies, and thereby influence their widespread preferred adoption in these rapidly growing economies.

Renewable energy projects get a positive push through CDM (over other candidate projects) because of the fact that such projects must assist developing countries in achieving sustainable development. According to the UNDP publication, *'Energy After Rio'*, renewable energy and energy efficiency must both be an integral part of any future energy system that addresses the issues of sustainable development. Furthermore, since rural development is an intrinsic part of sustainable development, RET-based CDM projects could be vital for many developing countries to meet their rural energy demand.

However, as one of the choices in the investment portfolio, RETs would have to compete with other options, e.g. energy efficiency, clean coal technologies, fuel switching, and carbon sequestration. While the host country is likely to ensure that the project is in line with its national sustainable development priorities, the investor would be inclined to prioritise the most cost-effective project. Therefore, proper optimization is quintessential while designing CDM projects based on RETs.

The box below outlines the salient features of the CDM and the section following details some of these features.

CDM in brief

- CDM projects assist host countries in achieving **sustainable development**. The host country will be the sole judge of the sustainable development criteria and whether the project in question falls in line with these.
- A particular CDM project should generate **certified emission reductions** (CERs) and should be proven feasible at the moment of submitting to the CER buyer.
- Public participation is essential in CDM projects. Project design should take in to account the comments of the local stakeholders.
- GHG emission reductions should be **additional** to any that would occur in the absence of the CDM project. This must be demonstrated in a **baseline** study.
- CDM projects are validated by **Designated Operational Entities** and registered by the **Executive Board** (EB).
- Emissions reductions are verified and certified by DOEs, CERs are issued by the EB.
- CDM projects are subject to levies by the EB. The EB will withhold part of the CERs (up to 5%) to cover administrative expenses and to assist Least Developed Countries

Project eligibility and approval

In order to ensure fair judgement of a given project's eligibility, a third party must first provide consent. To this end, projects are registered by a CDM designated operational entity (DOE) following validation of project design and resulting performance in emissions reduction. The project's emissions baseline is determined at this point, subject to possible future revision. Credits would be certified periodically, after the project becomes operational and its emissions performance has been monitored and verified.

At the registration stage, the specifications of relevant eligibility criteria for the particular project should be incorporated into the project approval process; compliance with such specifications should be a condition for future credit certification. Although credits are certified later on, the information provided and specifications incorporated at the time of project design approval and registration would enable project sponsors and potential investors to make reasonable projections of the future CERs that would be generated by the project.

2 Project baseline determination, monitoring & verification

There are several definitions for baseline. Few of them are discussed below.

Baseline is a scenario that reasonably represents the man-made emissions by sources of GHG emissions that would occur in the absence of the proposed activity. A baseline shall cover emissions from all gases, sectors and source categories listed under "CERs" within the project boundary. The baseline must be described in measurable terms so that the proposed project's environmental additionality can be determined.

Baseline is also defined as the overarching concept. The determination of whether a project is additional or not comes from calculating the difference between the verified emission of the project and the baseline emission. If the latter is higher, the project is "additional."

If the CDM host countries had quantitative targets themselves, there would be no need for baselines. But without them, the credibility of CDM depends on the degree it succeeds in reducing greenhouse gas emissions and avoids fictitious emission reduction reporting. The amount of emission reduction, obviously, depends on the emissions that would have occurred without the project. The construction of such a hypothetical state is known as the "baseline" of the project (Pearce, 1995).

In the process of developing a CDM project, each project developer has to submit a baseline study. This study comprises the construction of a baseline, an assessment of the project emissions, and a calculation of emission reductions. The purpose of such a study is to provide a transparent picture of what would have happened *without* the proposed project, what the CDM project itself comprises, including its emissions, and what the project emission reductions are expected to be. The study should be specified in such a manner that it provides the validation/verification body with a complete understanding of the assessment and calculation process.

Consequently, a baseline study document clearly, correctly and completely:

- describes the reference case of GHG emissions without implementation of the project, including a description and justification of all assumptions and calculations as well as the underlying data and references.
- describes the project and the factors causing and influencing GHG emissions (reduction) of the project, including a description and justification of all assumptions and calculations.
- defines project boundaries for the project, including the assumptions and method for defining project boundaries.
- identifies and describes the potential size and impact of any relevant foreseeable indirect GHG emissions outside the project's boundaries.
- includes data sources and references to other documents in a traceable manner.
- presents the baseline calculations and the underlying data to the validator separately, and in such an orderly manner (preferably in a spreadsheet file) that not only recalculation can be easily carried out, but also that any sensitivity analysis the project developer has done in determining the most feasible baseline can easily be repeated by the validator.

Based on these general requirements, the following components could be part of baseline studies.

- Description of project characteristics
- Description and determination of GHG sources and sinks and project boundaries
- Description of current delivery system
- Description and determination of key factors influencing project and baseline emissions
- Calculation of baseline emissions
- Estimation of project emissions
- Discussion of project lifetime
- Estimation of the emission reduction

Baseline methodology and calculation of the baseline emissions

The construction of the baseline is one of the most crucial elements of the CDM project activity design as it largely determines the size of the emission reduction to be credited. The project developer has to show the project's environmental additionality: the credits that can be generated by the project will be based on the extent to which project emissions will be lower than the emissions in the baseline situation.

A baseline is set up with the best knowledge and most recent information on future developments available at the time of or prior to the date of its set up.

In order to get consistency between the methodology used for the baseline on the one hand and the estimation of project emissions on the other hand, the same activity level (level of output) and project boundaries should be used as an input for both calculations.

Construction of the baseline

The baseline is the scenario that reasonably represents the GHG emissions that would occur in the absence of the proposed project activity. Starting now, the baseline should present the GHG emission values for this without-project situation for each year up and until the end of crediting period. The baseline must be a *conservative* estimate of the GHG emissions within the project boundaries.

To calculate the baseline emission values, as a guiding principle the actual or historical emission patterns will be used as a starting point. Since it is unlikely that the existing GHG emission pattern will remain unchanged in the future, a simple continuation of the actual emissions will usually not represent a reasonable baseline; nor will an extrapolation of the historical emissions by definition represent a reasonable baseline for such projects.

Baseline estimation for the project

SREPL proposes to generated power by installing biomass power plant and supply the power to Tamil Nadu State Electricity Board (TNEB).

As biomass is a CO_2 neutral fuel, the power produced by SREPL will be replacing fossil fuel based power generation by TNEB and hence emissions from such fossil fuels are also reduced i.e avoided generation of power and CO_{2e} emissions. And as such TNEB is purchasing power from SREPL, payment for the same to SREPL is ensured by TNEB through a 15 year power purchase agreement.

Thus the base line of the project is the power generation by TNEB and the GHG emissions under the base line scenario will be the emissions from power generation by TNEB.

It is proposed that a fixed base line for a period of ten years be considered for the proposed CDM project. The GHG emission under the base line scenario for the year **2000-01** has been considered as the emission in the base line scenario.

In the base line scenario power produced from fossil fuel based power generation units is only considered. This translates to the fact that the emission in the base line scenario has been calculated for fossil fuel based power generation only, **excluding hydro power** in the base year **2000-01.**

Present power scenario in Tamilnadu

Starting with the modest installed capacity of 156 MW (Mega Watt) with annual gross generation plus purchase of 630 MU (Million Units) at the dawn of independence, the TNEB has grown by leaps and bounds with generating capacity of 7905 MW as on 31.3.2002 comprising 2970 MW from four Thermal Stations, 228 MW from two Gas Turbine Stations, 1996 MW from 33 Hydro Stations, 19 MW from Wind Farms and 1913 MW as Tamil Nadu's share from Central Generating Stations. Generation from privately owned wind farms is 813 MW and TNEB's wind farm generation is 19.355 MW. The Board's gross generation during the year 2001-2002 was 43,923 MU. The total energy consumption during the same year was 35,196 MU. Details of the total installed

capacity available in the state for meeting the power requirements are given in **Table 1** below.

Table 1. Installed capacity Tamil Nadu as on 31.03.2002

(Capacity in MW)

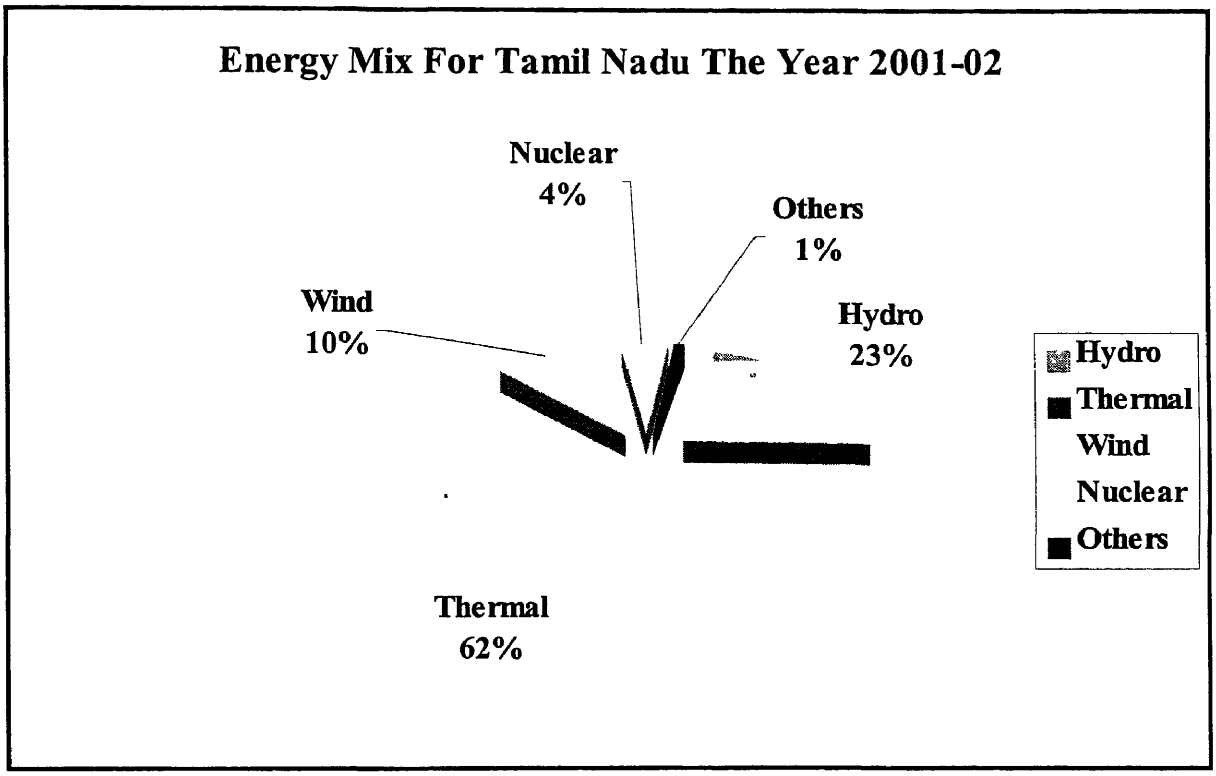
Ownership / Source	Units	Capacity
TNEB (5213.135)		
Hydro (1995.90 MW)		
Pykara	3 x 6.65 + 2 x 11 + 2 x 14	70
Moyar	3 x 12	36
Kundah I	3 x 20	60
Kundah II	5 x 35	175
Kundah III	3 x 60	180
Kundah IV	2 x 50	100
Kundah V	2 x 20	40
Mettur Dam	4 x 10	40
Mettur Tunnel	4 x 50	200
Lower Mettur	8 x 15	120
Periyar	4 x 35	140
Suruliyar	1 x 35	35
Papanasam	4 x 7	28
Servalar	1 x 20	20
Sarkarpathy	1 x 30	30
Sholayar I	2 x 35	70
Sholayar II	1 x 25	25
Aliyar	1 x 60	60
Kodayar I	1 x 60	60
Kodayar II	1 x 40	40
Kadamparai	4 x 100	400
Vaigai Small	2 x 3	6
Pykara Mini	1 x 2	2
Lower Bhavani Small	4 x 2	8
Punachi Mini	2 x 1	2
Maravakandy Mini	1 x 0.75	0.75
Lowerbavani RBC	2 x 4	8
Sathanur	1 x 7.5	7.5
Parsons Valley	1 x 30	30
Thirumurthy Mini	3 x 0.65	1.95
Mukurthy Mini	2 x 0.35	0.7
	Sub-Total	***1995.90***

Thermal (2970 MW)		
Ennore	2 x 60 + 3 x 110	450
Tuticorin	5 x 210	1050
Mettur	4 x 210	840
North Chennai	3 x 210	630
	Sub-Total	*2970*
Gas (227.88 MW)		
Kovilkalapai		107.88
Basin Bridge	4 x 30	120
	Sub-Total	*227.88*
Wind (19.355 MW)		
State Sector		19.355
	Sub-Total	19.355
Private Sector (1542.055 MW)		
Wind		813.395
Diesel		
Basin Bridge DEPP - I		196
Samalpatti DEPP		105.66
Basin Bridge DEPP - II		321
Basin Bridge DEPP - III		106
	Sub-Total	*1542.055*
Others (69.5 MW)		
TPCL		63.5
HITEC		6
	Sub-Total	*69.5*
Central sector share (1913 MW)		
Thermal		
Ramgundam STPS		520
Neyveli NLC TSI		500
Neyveli NLC TS II		521
Nuclear		
Madras Atomic Power Station		259
KAIGA		113
	Sub-Total	*1913*
	Grand Total	*8737.69*

Source. www tneb.org/stats.htm

The total capacity available for supply of power to the state of Tamilnadu in the year 2001-02 was 8737.69 MW. The power generation mix comprising sources like hydro, coal, gas/naphtha and nuclear energy sources are as follows:

Source		Capacity (MW)	Percentage Mix
Hydro		1995.90	23
Nuclear		372	4
Thermal (Coal /Lignite /Gas /Diesel based)		5467.54	63
Wind		832.75	10
Others		69.50	1
	Total	8737.69	100



The details of installed capacity in Tamilnadu since 1994 till 2002 and the increase in fuel source-wise installed capacity is provided below.

Energy mix for Tamil Nadu from 1994-2002

Year	Total Installed Capacity	Hydro Installed Capacity	% of Total	Capacity Addition	% Cap. Addition	Wind Installed Capacity	% of Total	Capacity Addition	% Cap. Addition	Thermal + Gas Installed capacity	% of Total	Capacity Addition	% Cap. Addition
1994-95	6578.00	1947.65	29.61			19	0.29			4281	65.08		
1995-96	6888.65	1947.65	28.27	0		19	0.28	0		4611	66.94	330	7.16
1996-97	7563.55	1947.65	25.75	0	0	675	8.92	655.545		4611	60.96	330	0
1997-98	7571.57	1955.70	25.83	8.055	0.41	675	8.91	0	0	4611	60.90	0	0
1998-99	7579.52	1963.65	25.91	7.945	0.4	675	8.90	0		4611	60.84	0	0
1999-00	8109.95	1995.90	24.61	32.255	1.62	925	11.41	250.18		4611	56.86	0	0
2000-01	8326.20	1995.90	23.97	0	0	832	10.00	-92.75	-11.14	4739	56.92	0	2.7
2001-02	8705.04	1963.25	22.55	-32.65	-1.66	833	9.57	0.45	0.05	5165.54	59.34	128	8.26

Energy mix for Tamil Nadu from 1994-2002 (...contd)

Year	Total Installed Capacity	Nuclear Installed Capacity	% of Total	Capacity Addition	% Cap. Addition	IIP & Others Installed Capacity	% of Total	Capacity Addition	% Cap. Addition	Total Capacity Addition
1994-95	6578.00	330	5.02			0	0	0	0	
1995-96	6558.65	330	5.03	0	0	0	0	0	0	
1996-97	7563.55	330	4.36	0	0	0	0	0	0	
1997-98	7571.57	330	4.36	0	0	0	0	0	0	
1998-99	7579.52	330	4.35	0	0	196		196		
1999-00	8109.95	382	4.71	52	13.61	196	2.42	0		
2000-01	8326 20	364	4.37	-18	-4.95	395	4.74	199	49.01	216.25
2001-02	8705.04	372	4.27	8	2.15	371.5	4.27	-0.47	-11.01	434.99

Details as regards generation of power from the power plants in the state of Tamilnadu are given in **Table 3** below.

Table 3. Performance of Power Plants Supplying Power of Tamilnadu*

(Figures in MU)

Name of Power House	Installed capacity (MW)	Capacity at the command of TNEB (MW)	Generation during 2000-01 (MU)
A. Hydro			
Pykara	70	70	344
Moyar	36	36	148
Kundah I	60	60	295
Kundah II	175	175	739
Kundah III	180	180	433
Kundah IV	100	100	142
Kundah V	40	40	87
Aliyar	60	60	183
Suruliyar	35	35	92
Kadamparai	400	400	186
Pykara Mini	2	2	6
Mettur Dam	40	40	83
Mettur Tunnel	200	200	623
Papanasam	28	28	125
Periyar	140	140	486
Sarkarpathy	30	30	159
Sholayar I	70	70	326
Sholayar II	25	25	56
Kodayar I	60	60	237
Kodayar II	40	40	89
Servalar	20	20	35
Lower Mettur	120	120	430
Vaigai Small	6	6	20
Lower Bhavani Small	8	8	30
Punachi Mini	2	2	2
Maravakandy Mini	0.75	0.75	--
Lower Bhavani RBC	8	8	14
Sathanur Dam	7.5	7.5	16
Parsons Valley	30	30	64

Name of Power House	Installed capacity (MW)	Capacity at the command of TNEB (MW)	Generation during 2000-01 (MU)
Thirumurthy Mini	1.95	1.95	--
Mukurthy Mini	0.7	0.7	--
Total		**1995.9**	**5450**
B. Thermal			
Ennore	450	450	753
Tuticorin	1050	1050	7934
Mettur	840	840	6422
North Chennai	630	630	4355
Total Thermal		**2970**	**19464**
C. Gas Turbine	**227.88**	**227.88**	**215**
D. Purchase			
Neyveli TS-1	600	500	3328
Neyveli TS-2	1470	521	2972
MAPP	470	259	710
NTPC (RSTPS)	2100	520	4900
Kaiga	440	105	551
IPP & others	395.16	395.16	4156
Total Purchase		**2300.16**	**16617**
Total for Tamil Nadu		**7493.94**	**41746**

* Excluding power generation from TNEB installed and private wind farms

The power generation from TNEB installed wind farm and from private wind farms are 18 MU and 1077 MU respectively for the year 2000-2001.

The share of ownership of the installed capacity in the state among TNEB, Private and Central sectors is given below:

Ownership	Percentage of installed capacity
TNEB	60 %
Private sector	18 %
Central sector	22 %

The projects expected to be commissioned during 2002-2003 (352.80 MW).

Project	Capacity (MW)
Gas	
Valuthur GTPP	95
Lignite	
Neyveli Zero Unit (IPP)	250
Hydro	
Amaravathi HEP	4
Aliyar Small HEP	2.50
Perunchani HEP	1.30

From the above table and from the table on Energy mix since 1994, it is evident that capacity additions in Tamil Nadu will be mostly based on thermal viz, coal, lignite and diesel (including LSHS).

TNEB claims that there has been no power cut for the industries for the last two years. On the contrary, the TNEB has been advertising in the newspapers that the power to the industries would be available within a specified time frame depending on the volume of the work. The TNEB has the full capacity to meet the entire demand of the industries. TNEB has made a very detailed analysis of power demand and supply picture for the next five years which is given below:

(MW)

Year	Projected demand	Availability	Surplus
2000-2001	6029	6160	131
2001-2002	6277	6416	139
2002-2003	6524	7307	783
2003-2004	6771	8224	1453
2004-2005	7018	8592	1574

Future capacity addition

India

On account of inadequate generation capacity, the country is plagued by power shortages. The total energy shortage, during 2000-2001, was 39,816 million

units, amounting to 7.8 per cent and the peak shortage was 10,157 MW translating to 13 per cent of peak demand. Based on the demand projections made in the 16th Electric Power Survey, over 1,00,000 MW additional generation capacity needs to be added by 2012 to bridge the gap between demand and supply of power.

The Ministry of Power (Government of India) has taken a comprehensive and realistic review of the various power projects to prioritise those, which can be commissioned in the X and XI Plans. Based on this review, a capacity addition target of 46,500 MW has been tentatively fixed for Central Public Sector Undertakings under the Ministry of Power. At the State level, the SEBs/State utilities and private sector will add about 41,800 MW. For optimal development of the electricity energy in its totality, an integrated approach, including capacity addition through nuclear and non-conventional energy, has been adopted.

The capacity addition targets of 6400 MW through nuclear power and 10,700 MW through non-conventional resources have been accordingly fixed for the period up to 2012.

As per the free run studies using EGEAS model (CEA Report June 1999), the capacity requirement during 10^{th} plan (2002-07) and 11^{th} plan (2007-12) are 54,090 MW and 58,940 MW respectively. Out of these, the share of thermal energy is around 53%, hydro and nuclear being around 39% and 8% respectively during both these 5 year plans.

Lignite has emerged to be most economical fuel choice for power generation. The large coal reserves in the country provide a ready and economical resource and ensure energy security. Hence, coal has been identified as the mainstay fuel for power generation till 2012. Emphasis has been laid on setting up large pit head stations to avoid high costs associated with transportation of high ash bearing Indian coal and overstraining the already stretched rail network. Imported fuels will be required for power generation in case of shortfall in production of domestic resources for power generation.

Introduction of super critical technology and clean coal technologies is also planned to generate power with maximum efficiency and minimal pollution. The government is taking environmental initiatives in keeping with the global developments and mechanisms. Thus, the government is striking a fine balance

between the power development imperatives and the emerging concerns for the environment.

Tamil Nadu

TNEB has programmed to create an additional capacity of 3870 MW during the next five years out of which 2000 MW would come from the Independent Power Projects (IPPs). The above availability takes into account these additional capacities, An independent study by CRISIL has also confirmed that the creation of additional capacity of 3870 MW would be sufficient. It is, thus, clear that there will be no shortage of power in Tamil Nadu, particularly, to the industries in the coming years on account of proper planning and execution of various schemes by the TNEB.

Tamilnadu is known for its vast lignite resources and access to coal in Andhra Pradesh and Orissa. The state has already experienced import of Australian coal. Hence the likely future addition of power plants in the state will favour coal / lignite as the fuel. IPPs are implementing the projects based mostly coal, diesel or LSHS diesel. A couple of mega power projects being planned in Tamil Nadu of capacities in the order of 1000 MW and 1500 MW are based on coal. Hence Tamil Nadu in the future would like to add capacities based on their resource strength i.e. coal. The scenarios based on the CEA projections for Tamil Nadu further confirms the capacity addition based on coal/lignite energy resources, which predicts a growth in capacity addition by thermal – coal based and lignite based to the tune of 54 % and 20 % respectively at the end of 11^{th} five year plan (2012).

Emission reductions from the project & crediting period

GHG emission sources

Direct on-site emissions

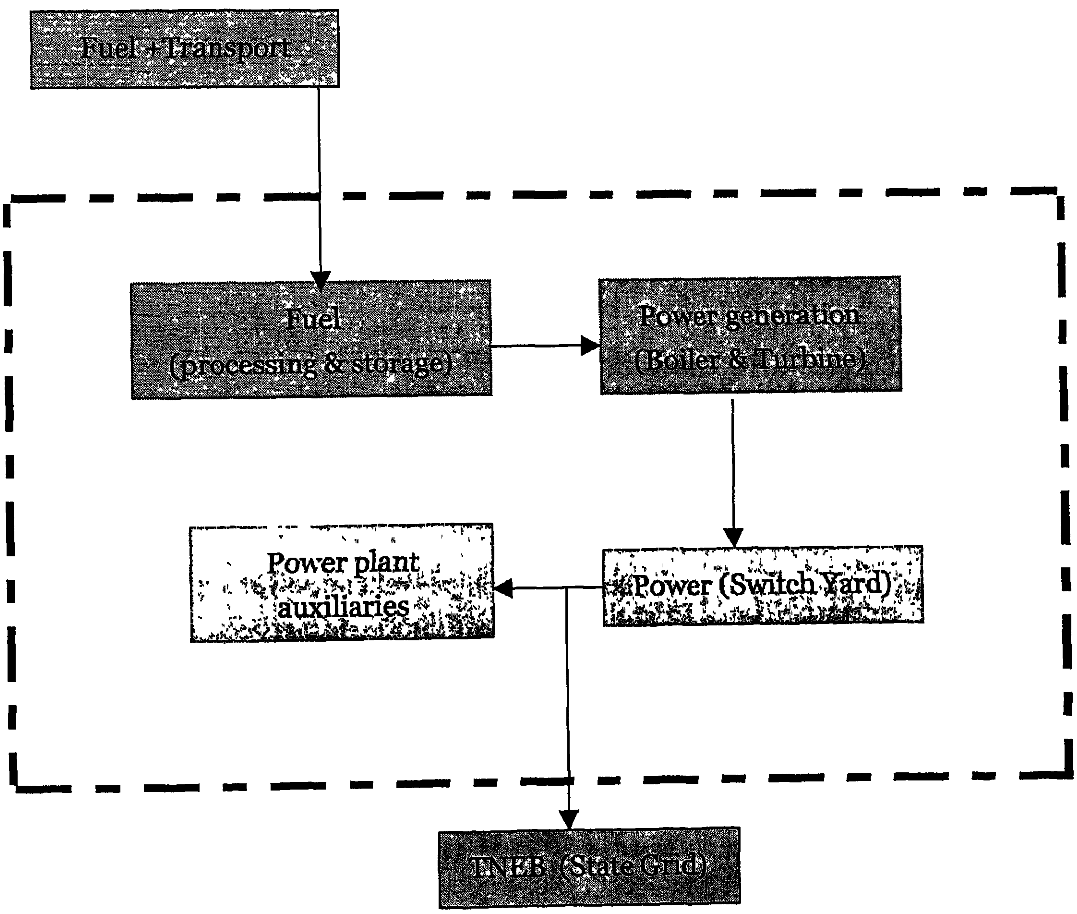
The major direct on-site emissions resulting from the operation of the project will be the emissions due to combustion of biomass in the boiler. As such there are no other process emissions within the project boundary. As biomass is considered as CO_2 neutral fuel (i.e. emissions generated due to biomass combustion would be equivalent to that sequestered during growth of biomass). Hence the project activity does not lead to any direct on-site GHG emissions.

Direct off-site emissions

The off-site GHG emissions constitute those from the fossil fuels (diesel/ petrol) used for biomass transportation to the project site. As emissions related to transportation of fossil fuels are not considered during estimation of baseline emission and due to sourcing of biomass from the nearby vicinity of the project site, the off-site emissions are not influenced greatly by the project and hence not considered. It may further be noted that emissions related to fossil fuel transportation will be higher as compared to that resulting from biomass transportation. Thus the emission reductions being calculated will be an conservative estimate.

Project boundary

The boundary for the project is the physical boundaries of the project which does not consider fuel transport. The project boundary is as given below.



Emissions in the baseline scenario

CO_2 is the only GHG considered, as it is not possible to estimate the emission of other GHG for production of power. This is in view of the availability of data regarding emission of other GHG for production of power. For estimating emission intensity of fossil fuel based power plants characteristics of different fuels used is considered to be as given in **Table** below.

Table Characteristics of Fossil fuels used in Power Plants

LSHS	
Carbon content by Wt.	84.5 %
Calorific value	9565 K Cal / Kg.
Percent Oxidization	*98 %*
Naphtha	
Carbon content by Wt.	80 %
Calorific value	10560 K Cal / Kg.
Percent Oxidization	*98 %*
Natural Gas	
Carbon Content by Wt.	75 %
Calorific Value	12300 K Cal / Kg.
Percent Oxidization	*99.5 %*
Coal	
Carbon Content	40 Percent
Calorific Value	3816* K Cal / Kg.
Percent Oxidization	*98 Percent*

* CEA report

Based on the GHG emission intensity of individual fossil fuel based power plant and the contribution by the individual power plant, the aggregate CO_2 emissions for production of power in the state of Tamil Nadu in the year 2000-01 has been worked out to be **56.65 Million Tons.**

Based on the above the emission of CO_2 per unit of power supplied to the grid in the state of Tamil Nadu in the base year (2000-01) has been estimated to be as follows:

Fossil fuel based power to grid*	**54229**	**Million units**
Total CO_2 emission	**56.65**	**Million Tons of CO_2**
Emission per unit of fossil fuel based power (weighted average)	**1.04**	**kg. / unit of power**

* including nuclear power

In the above calculation, power generation from hydro resources T&D losses for the state of Tamil Nadu **have not been** considered for estimating the baseline emission. However power generation from nuclear is included.

As indicated above, the baseline emission is 1.04 kg of CO_2 per unit of fossil fuel power generation.

The above baseline emission is recommended for use for estimating the emission reduction from the proposed project based on the quantum of annual power generation. A ***static baseline*** is recommended for the project with a crediting period of 10 years.

The power generation from the project for ten years from the year 2004-2005 and the corresponding CO2 emission reductions are given below.

MUs / Million Tons

Year	1	2	3	4	5	6	7	8	9	10
Power generation	43	43	43	43	43	43	43	43	43	43
Emission reductions	0.045	0.045	0.045	0.045	0.045	0.045	0.045	0.045	0.045	0.045

Monitoring and verification plan

A monitoring plan describes the relevant factors and the key characteristics that will be registered, measured or otherwise monitored by the project organization on a regular basis.

The monitoring plan need to incorporate all project factors that are of importance for controlling and reporting of project performance and clearly identify frequency of, responsibility and authority for registration, monitoring and measurement activities.

In the monitoring plan, the project organization have to describe the methods it will employ for data registration, monitoring, measurement and calibration.

Records proving method validity and accuracy shall be kept and be available on request. Where applicable the methods used for quality assurance of monitoring and measurement activities have to be described.

Monitoring

Monitoring of project performance is crucial to ensure that emission reduction units claimed from a CDM project activity are justified. The monitoring activities should ensure that indicators that show the GHG emission level from the project are recorded in a way that enables comparison with the baseline emission scenario. Subsequently the difference in the real and the baseline emissions can be claimed as emission reductions.

Monitoring and recording of indicators will also provide a foundation for presenting ERUs for verification by a third party, and ultimately end up in reporting of verified emission reductions to the parties involved in the project and towards the UNFCCC.

Monitoring of indicators must ensure that the indicators are reliable and valid. Reliability means that the indicators give consistent and accurate values/readings when they are measured by the determined method. Validity points towards the fact that the indicator must have a clear connection with the desired result.

Monitoring activities should include specific indicators, constants and variables necessary to sustain claimed emission reductions, as well as creating a transparent picture sufficient for verification of these. In addition the project will also be required to monitor and report indicators that show indirect effects (including leakage) resulting from the project.

Project-specific M&V

To enhance the reliability of indicators used for crediting, it is recommended to use for monitoring and reporting, to the extent possible, those indicators which are already in use for normal business practices. The advantage being that such indicators already have been verified by parties outside the project.

This enables the project developer to use established data records from their archives, instead of developing a new set of records.

The project typically will have to maintain records related to the following :

- Fuel purchase
- Fuel use in the boiler
- Gross power generation
- Auxiliary power consumption
- Records of sale of electricity to TNEB

While the project management has to maintain records for the incoming biomass to the project site and consumption of biomass in the boiler, power sold to TNEB will be automatically metered and recorded in TNEB meter. The reading is printed and the payment is made accordingly by TNEB. Hence the project management has to maintain this record which is already authenticated by TNEB.

State-of-the-art equipments for measuring the biomass consumption by the boiler, gross power generation and auxiliary power generation will be installed by the project management. The system requirement for measuring the above parameters will be decided during the design of controls and instrumentation for the power plant. The net power sale to TNEB can also be recorded and maintained by the project management in addition to that by TNEB itself.

The verifying authority (DOE) will examine the above records for correlating the total biomass purchase, consumption and power generation and also scrutinise the TNEB's monthly power purchase record.

After verifying the records, DOE shall certify the emission reductions interms of CERs and forward the same to CDM Executive Board on behalf of the project management for them to issue the CERs after adjusting their proceeds towards adaptation funds.

The frequency of such monitoring, verification and certification is recommended twice a year.

3 Additionalities & sustainable development

Additionality

Article 12 of the Kyoto Protocol provides that, in order to be creditable, emissions reductions must be "additional to any that would occur in the absence of the certified project activity."

Additionality tests are designed to prevent credits going to projects that would happen even without the CDM – such interventions are called 'free rider' credits. There are two types of additionality testing :

Environmental additionality – real, measurable and long-term emissions reductions that are additional to any reductions that would have occurred in the absence of the certified project activity
Financial additionality – funding for the CDM project must be additional to official development assistance, including contributions to the Global Environmental Facility.

To pass the *environmental additionality* test, the project developer has to identify and document measures that reduce emissions, while excluding measures that would have been introduced anyway. One way to motivate for environmental additionality is to show that the technology to be used is the best available under the circumstances and better than the typical baseline technology. Technology comparisons can be made at local, national, and regional levels, against pre-established benchmarks.

Financial additionality, the second key requirement, means that project financing has to be additional to funds already allocated by the investor country to official development assistance. The principle here is that CDM projects should not divert or decrease already scarce development aid. The financial additionality criterion includes bilateral official development assistance and multilateral grant funding. The challenge in interpreting the financial

additionality criterion is that official development assistance from many Northern countries is already falling, so it is difficult to judge whether money is being diverted. Some practitioners argue that the financial additionality constraint should not apply to the financing of feasibility studies or to the monitoring and capacity building aspects of CDM projects.

What about projects that are financially viable – on paper at least – without carbon credits? Would not these projects have happened anyway, and therefore not be environmentally additional? Possibly, but project developers can still motivate for additionality if CDM activities help to remove barriers that would have prevented implementation. Such barriers would include technology availability, lack of staff training, high investment risks, and poor management capacity etc.,

Project developers have to argue convincingly that a carbon investment and technology transfer package can help to overcome these barriers. One such barrier is that at present there is very few State Electricity Boards who guarantee that electrical power generated by independent producers will be bought by them.

Examples of other barriers include:

- lack of in-house technical or financial capacity to analyse energy efficiency
- opportunities;
- poor managerial incentives;
- high technical risks or lack of host country demonstration of a particular new
- technology or process;
- split incentives between energy provider, paying customer, and end-user;
- lack of familiarity with performance contracting and energy service company models of third party financing;
- limited access to favourable finance on the part of local investors. (Minerals & Energy Policy Centre, South Africa)

The additionality test must balance the objective of encouraging private sector investment with that of ensuring that the vast majority of projects earning emissions reduction credits are delivering real reductions. The transfer, via the CDM, of superior clean technologies to host countries should also be encouraged. Specific approaches that have been suggested are:

Accept certain types of projects are additional by definition: The Center for Clean Air Policy contends that there be no additionality standard for certain types of projects that, by definition or implication, clearly reduce emissions. In its view, such projects include: fuel switching to less-emitting fuels than those currently in use, actions that improve energy efficiency and all renewable energy projects that displace electricity from emitting sources or that add emission-free capacity to a country's electricity supply system.

Accept profitable projects as additional if they overcome barriers: The EPA and the International Energy Agency (IEA) argue that profitable projects be allowed to earn credits if they introduce new technology or contribute to overcoming technological, financial, informational or institutional barriers.

Adopt benchmarks for additionality: Projects that generate GHG reductions in excess of baselines formulated generically for the type of activity in question are deemed to meet the additionality test, while those that fail to meet the benchmark do not. A recent study by Hagler Bailey for the EPA concludes that such benchmarks could serve as determiners of additionality for projects in some sectors. In other cases a combination of generic benchmark criteria applied on a project-by-project basis could be used (United Nation Foundation, 2000).

Additionality for the project

As the project is falling under renewable energy sector, the project confirms to environmental additionality. The emission reductions resulting from the project is greater than the baseline emissions. The technologies being employed for the project is travelling grate boiler (26 TPH ,66 ata, 485 deg C) and single extraction 6 MW steam turbine, are the state of art technologies available in India. The technology description is provided in detail in the DPR of the project.

As far as the financial additionality, the project is seeking financial closure from financial institution(s) in India and hence would not enjoy any funds assistance out of ODA. The project does not also enjoy capital subsidy from the Government of India.

No other additionality is considered for this project.

Sustainability

The project envisages contributing to economically, environmentally and socially sustainable development of the region and country through a profitable operation of the plant and thereby, create sustainable shareholder value.

The strategic objectives identified by the project to achieve the stated goals include increased share of renewable energy in the Indian Context more specifically through a focus on agricultural waste, increase rural incomes, reduced vulnerability and empowerment of the vulnerable sections of society.

More specifically, the project shall contribute to the sustainable development of the region and country as:

a) The project is aligned with the policies of Ministry Of Non-Conventional Energy Sources (MNES) and Government of Tamilnadu.

b) The investment shall have a multiplier effect on the economy of the region.

c) The southern region at the end of the 9th plan was expected to have an energy deficit of 8%. The unit shall contribute, though in a small measure, to bridging the gap between the supply and demand of power in the state and the region

d) More importantly, the bridging of this gap shall be by the use of a less polluting and renewable resource and particularly with lesser climate change implication.

e) This project shall demonstrate successful use of casurina for energy generation. This could spur not just replication of the same but also experiments with other agri-residues that are presently not being used.

f) This fuel addresses one of the major concerns of coal based power plants viz disposal of fly ash. The proposed fuel here has about 2% ash content as compared to 30% to 40% ash content in Indian coal.

g) The project shall directly employ about 50% persons in the proposed unit and as per MNES estimates, 100,000 mandays of work is created per 5 MW of electricity produced per year.

h) The unit shall add to the rural incomes by sales of biomass for the plant which shall add to rural household income.

i) Increased income security shall contribute to the empowerment of the most vulnerable sections of the society.

j) In the long run the replication of the units may result in considerable improvement in the income status of the rural communities of the region and the price of the waste may increase to a level prompting switch to other fuels like LPG etc. for domestic use. This has besides GHG implications also implications for health as Indoor air pollution annually kills 150,000 women in India.

The purpose of the project essentially is to create and enhance sustainable shareholder value. This can be achieved through

a) Sustained profitable operation.

b) Creation of goodwill and reputation asset.

c) Maintaining good stakeholder relations.

d) Conservation of the environment in which the unit is set-up.

Towards this end the project management has already initiated the following.

a) Appropriate project design, adequate Power Purchase Agreement, emphasis on efficient project execution without time and cost over runs, development and deployment of appropriate management and operational control systems and capacity building across the supply chain to ensure smooth operations.

b) Steps to highlight the achievements and contribution of the project to the economy, environment and the society.

c) Training of the farmers to increase casurina yield, rural education programmes and other community development works to maintain good stakeholder relations and share the benefits arising from success of the project.

d) The project is designed as a cleaner energy generation project. This project directly contributes to reduced GHG emissions, reduced specific water consumption, reduced specific solid waste generation. Further, appropriate environmental performance monitoring and control systems shall be installed.

4 CDM – Project financial aspects

The salient feature of the project before considering CERs as mentioned in the DPR is provided below.

Project features (as per DPR)

1.	Project location	Village Vanur, District Villupuram, Tamilnadu
2.	Proposed Installed capacity of the power plant	6000 kW
3.	Biomass proposed to be used	**Major Fuel : Casuarina**
4.	Other biomass	Rice Husk, Ground Nut Shell, Canetrash, Proposis juliflora
5.	Technology	Travelling grate boiler & single extraction cum condensing turbine
6.	No. of boilers to be installed	One
7.	Capacity of the boiler	26 TPH
8.	Boiler outlet steam parameters	66 Ata 485 Deg C
9.	No. of turbo generator to be installed	One
10.	Turbo generator type	Single extraction cum condensing
11	Maximum gross power generation	6048 kW
12.	Power plant auxiliaries consumption	595 kW
13.	Net maximum exportable power	5453 kW
14.	No. of hours of plant operation	8040 hrs/year
15.	Plant Load Factor (%)	90
16	Net annual saleable energy to Grid	43.8 Million units
17.	Total project cost Rs. in Lakhs	2375.00
18.	Installed cost per MW of generation	Rs.395.83 Lakhs
19.	Project Financing (Rs. in Lakhs)	
	Grant from MNES	Interest Subsidy
	Equity	712 (30%)
	Term loan from financial institutions	1662 (70%)
20.	Net Surplus cash at end of 10th Year Rs. in Lakhs	641.80
21.	Cost of Generation (Rs./kWh)	1.71
22.	Project IRR	16.39 %
23.	Average DSCR	59.061.49
24.	Breakeven capacity	49.80%
25.	Sale Price of Energy	Rs. 3.00 per kWh
26.	Price of Fuels Rs.per Ton	900 (including handling wastage)
27.	Biomass Requirement MT per Year	52,260

The present financial analysis of the project has been reworked after including the following parameters and values:

Annual estimation of CERs	:	44631
Cost per CER	:	5 USD (@ Rs 50 per USD)
Annual revenue	:	Rs. 111.58 lakhs
Transaction cost	:	Rs. 44 lakhs @ 2% of project cost
Annual Expenses	:	Rs. 2 Lakhs (@ 2% of CER revenue towards EB proceeds)

The change in the project Internal Rate of Return (IRR) after considering the above parameters are given below :

	Without CER	With CER
IRR (%)	21.68	24.69

As evident from the above table, there has been a net increase in the project IRR by 3%. It is also clear that the project is very much viable and attractive even without the considering CERs.

In addition to further improving the viability of the project, CER revenue improve foreign exchange inflow to the nation, and may also be seen as a mitigating factor to meet any contingency situation during the operation of the project such as delay in payment by TNEB or lowering of tariff by TNEB, increase in cost of biomass and other O & M expenses.

Ownership / Source	Installed capacity (MW)	Capacity at the command of TNEB (MW)	Gross generation (2000-01) (MUs)	Auxiliary Consum (MUs)	Net Generation (MUs)	Gross heat rate kCal /kWh	Net heat rate kCal /kWh	Carbon Emission for Net generation kg/kWh	CO2 Emission for Net generation kg/kWh	Weighted Average CO2 Emission kg/kWh
TNEB Thermal										
Coal										
Ennore	450	450	[illegible]	[illegible]	[illegible]	3620	4283	0 44	1 61	1 04
Tuticorin	1050	1050	7934	606	7328	2483	2688	0 28	1 04	
Mettur	840	840	6422	520	5902	2506	2727	0 28	1 03	
North Chennai	630	630	4355	406	3949	2500	2823	0 29	1 06	
Gas (all assumed NG)										
Narimanam	10	10	[illegible]	[illegible]	14.65	2100	2165	0 13	0 48	
Basin Bridge	120	120	[illegible]	4.92	159.08	2100	2166	0 13	0 48	
Kovilkalappal	107.88	107.88	[illegible]	1.08	34.92	2100	2165	0 13	0 48	
Private - Thermal										
IPP - Diesel Total			4156	166 24	4156	2000	2083	0.16	0.66	
Basin bridge GMR Vasavi	196	196								
Samalpatti	105	105								
Others	94.16	94.16								
Central - Thermal										
Lignite										
Neyvel TS-1	600	500	4157 68	447 18	3710 5	4027	4512	0 45	1 64	
Neyveli TS-2	1470	521	10515 5	1015 88	9499 62	2932	3246	0 32	1 18	
Coal										
NTPC - Ramagundam	2100	520	15902	1431	14471	2966	3259	0 33	1 23	
Nuclear -										
MAPP	340	259	2515	N A	2515					
Kaiga	440	103	1852	N A	1852					
					54229 30262					

FUEL PROPERTIES

	COAL	Source	LIGNITE	Source	GAS	Source	LSHS	Source
CV kcal/kg	3816	CEA	2664	CEA	12300	TERI	9565	CEA
% CARBON	0 4	TERI	0 27	www osc edu	0 75	TERI	0 845	TERI
OXIDISATION %	0 98	TERI	0 98	TERI	0 995	TERI	0 98	TERI

ASSUMPTIONS

All the above power generation data are for the year 2000-2001
Power generation from small hydro not included
Power generation from nuclear included
T&D losses not included
Power generation for coal based NTPC- ramagundam has been calculated @PLF of 89 6 (2000-01) as compared to 15859 2 MU @ 89 36 PLF for year 1998-99 (source www cercind org)

SOURCE

TNEB Report at a glance , 2001-02
www tneb org
Source for heat rates are www cea nic in, powermin nic in, CEA Report by its performance evaluation division
Source for Nuclear power is www npicl org
Source for auxiliary power percentage for gas power plants is from www cea nic in
Source for auxiliary power for diesel based power plant is www cea nic in